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Australia's World Scale Gas Resources, Its Markets and Why New Approaches Are Required

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Abstract

Australia is uniquely positioned globally as a major energy provider, but this comes with multiple challenges that must be overcome to realize its full potential. LNG developments that are nearing fruition are set to make Australia the largest supplier of LNG in the world. The Asian LNG market continues to be the growth market. The development of the world's first coal bed methane (coal seam gas) to LNG projects on the east coast has created a robust east coast LNG export market, which in the near future is expected to coincide with domestic energy shortages arising from low exploration activity, maturing fields, higher costs, the interaction of government policy, commercial decisions and activism. As a result, unique approaches to project management and community relations have been developed that are complementary to the Australian consumer's needs for reliable, affordable and cleaner energy. The east coast demand for gas is likely to trigger new development of onshore Northern Territory gas in the short term, if political opposition can be managed. In Western Australia, new approaches leverage technologies such as floating LNG, and more utilization of existing infrastructure and plant capacity to achieve lower costs. This paper outlines Australia's natural gas supply & demand and the challenges to be faced in the coming years.

Introduction

Australia has large supplies of conventional and unconventional natural gas. In the past the domestic market has been supplied by onshore developments in the Cooper Basin of South Australia and Queensland, the Surat Basin of Queensland, the Gippsland and Otway basins, offshore from Victoria, and the Carnarvon Basin, offshore from Western Australia. Today the conventional gas supplies in the Cooper Basin and the Surat Basin are largely depleted and those in the Victorian offshore Gippsland and Otway basins have begun to decline. The Carnarvon Basin has supplied the domestic market for gas in Western Australia but has also developed a substantial liquefied natural gas (LNG) export market. LNG export programs have also been developed from the Bonaparte Basin, offshore from the Northern Territory and the coal seam gas fields of Queensland. Further developments in the Carnarvon Basin and Western Australia's offshore Browse Basin are planned for the future to expand the LNG export markets. In eastern Australia a pipeline network links most of the major basins and the markets of Queensland, New South Wales, Victoria, Tasmania and South Australia, making this an integrated market. But, with conventional supplies declining on the east coast, and the unconventional coal seam gas reserves being developed for export as LNG as well as a source of supply for east coast demand, more gas supplies have been urgently sought. This has been perceived as a shortage of gas in the eastern market, although others claim that it is actually a shortage of gas at formerly low prices. How the east coast demand is to be met is a challenge for the future. Figure 1 shows that the Australian population is expected to grow reasonably linearly from the current (2018) estimate of 25 million people to a population of 42 million by 2050 and 70 million by the turn of the century (2100). This growth in population is expected to increase the demand for domestic gas but whether this turns into a linear increase in demand depends on the future energy mix, which may be affected by future government policy. Australia is also well placed to serve the large population centres of Asia, and, consequently, the demand for LNG from Asia is expected to feed a robust export market for Australian LNG.

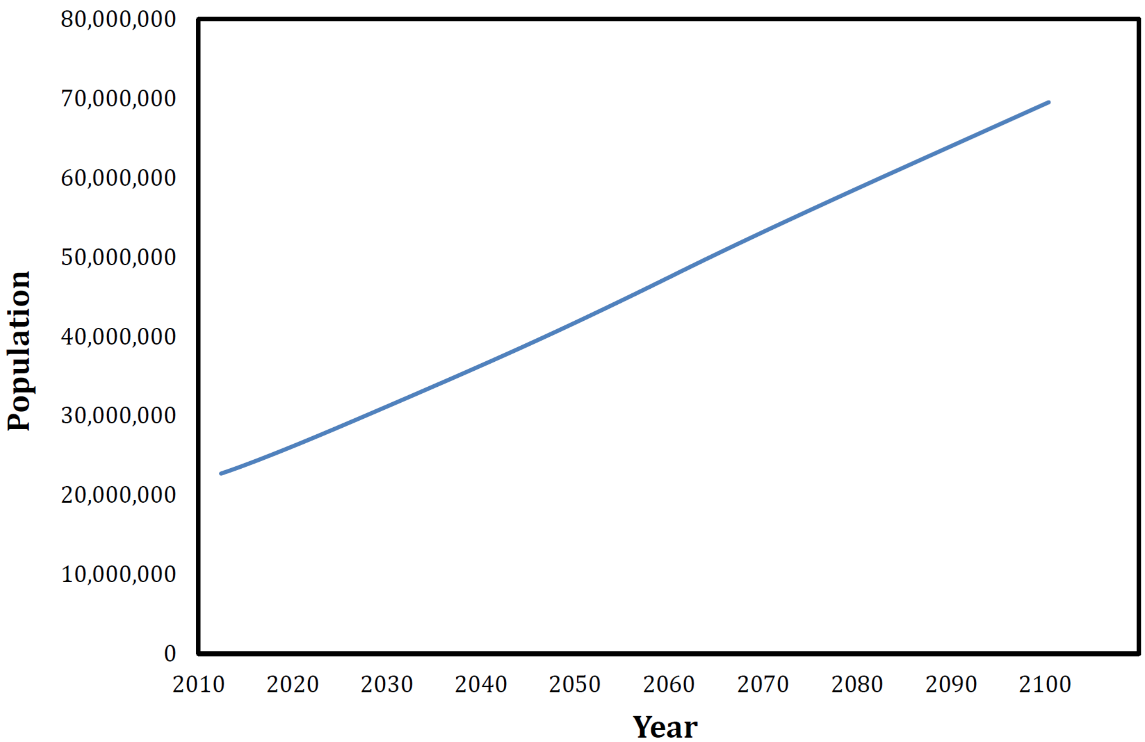

Figure 1—Australian Population Forecast (data from Australian Bureau of Statistics)

Domestically Australia sources most of its energy from oil, natural gas and coal, as shown in Figure 2. Wind and solar power collectively have moved ahead of hydroelectric power in recent years, but all three are still relatively small players in the nation's energy supply.

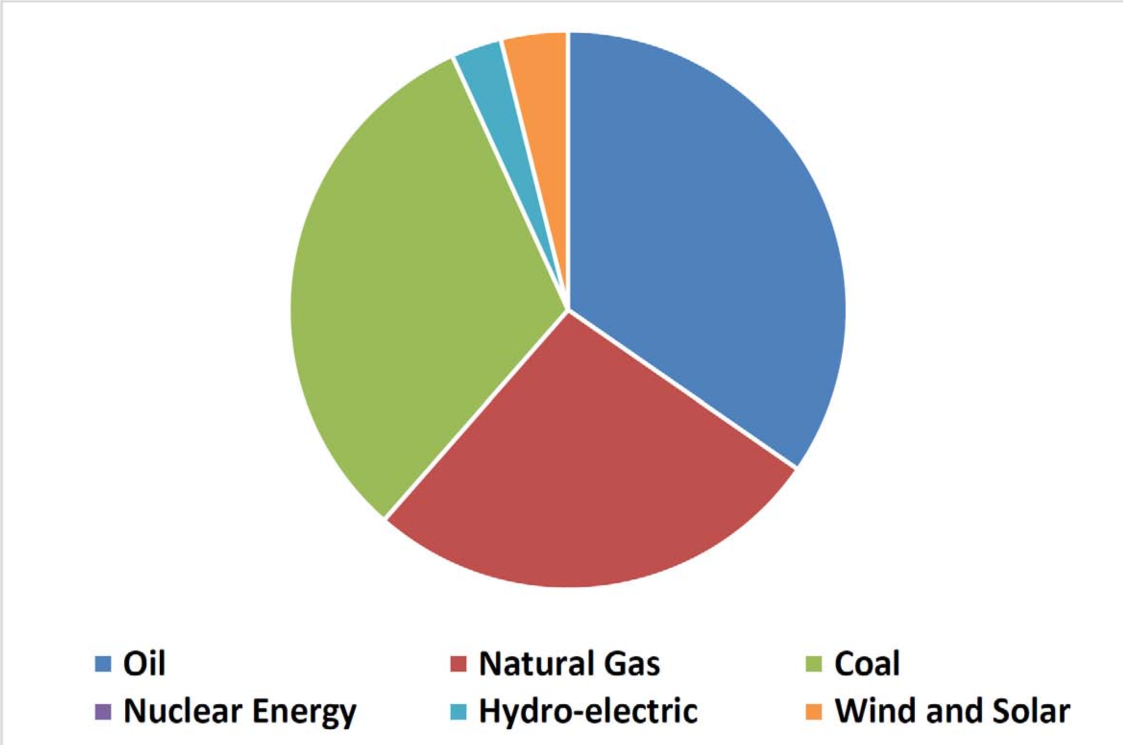

Figure 2—Australia's Energy Consumption by Fuel.

Table 1 shows that electricity generation is the primary source of energy, followed closely by transportation, with industrial manufacturing a distant third. However, the demand for transportation fuel is likely to grow more rapidly and overtake electricity generation by 2035.

Table 2 shows that most of Australia's electricity is generated from coal, but natural gas and renewables provide a significant proportion of the current electricity supply. Moreover, by 2035, renewables, such as hydroelectric, wind, solar, bioenergy and geothermal, are expected to overtake electricity generation from natural gas.

Table 1—Australian Primary Energy Consumption by Sector (Data source: Australian Bureau of Statistics)

Sector	2014-15 (PJ)	2034-35 (PJ)	2049-50 (PJ)	% share 2014-15	% share 2049-50	% average annual growth 2014-2015 to2049-50
Electricity generation	2054	2268	2278	34	27	0.3
Agriculture	103	133	157	2	2	1.2
Mining	523	1051	1211	9	14	2.4
Manufacturing	1244	1456	1618	21	19	0.8
Transport	1752	2325	2723		32	1.3
Commercial & Residential	339	427	554	6	6	1.4
Australia total	6061	7661	8541	100	100	1

Table 2—Australia's Electricity Generation by Energy Source. (Data source: Australian Bureau of Statistics)

Energy type	2014-15	2034-35	2049-50	% share 2014-15	% share 2049-50	% average annual growth 2014-2015 to2049-50
Non-renewable	**216**	**252**	**265**	**85**	**80**	**0.6**
Coal	163	200	214	64	65	0.8
Black coal	117	153	163	46	49	1.0
Brown coal	47	47	51	18	15	0.3
Gas	50	49	48	19	14	−0.1
oil	3	3	3	1	1	0.0
Renewables	**39**	**63**	**67**	**15**	**20**	**1.5**
Hydro	19	19	18	7	6	−0.1
Wind	16	32	33	6	10	2.0
Bioenergy	2	5	6	1	2	3.7
Solar	2	3	6	1	2	3.0
Geothermal	0	4	4	0	4	
Total	**255**	**315**	**332**	**100**	**100**	**0.8**

Global and Australian gas supply and demand

The history of natural gas production in Australia is shown in Figure 3. Until 1989, all of the gas production was used domestically [See Figure 3]. However, in 1989 exports of LNG commenced from the North Rankin reservoir in Western Australia's Carnarvon Basin. Figure 3 also shows that the reserve life of Australia's natural gas resources has been as high as 83 years (in 1980). However, with the development of new LNG facilities, the reserve life has been falling rapidly and as of 2017, it stood at 38 years. New gas reserves are not being added rapidly enough and these are urgently needed to serve the east coast market and to feed the robust LNG export market that has been won at considerable capital cost. The reserve life is projected to fall to 20 years by 2025. This could represent a critical supply crunch for both the export LNG market and the domestic demand.

The national gas pipeline network in Australia is not interconnected. However, three separate gas pipeline grids have developed that, at this time, divides the country into three separate markets, which are termed the western, northern and eastern markets. The major eastern population centres of Brisbane, Sydney, Melbourne, Hobart and Adelaide are tied into the eastern grid. The northern pipeline grid serves Darwin, while the western grid serves Perth plus the mining developments of Western Australia. A 12 inch gas line was completed in July 2018 to feed excess gas from the northern network to the eastern market, but, at the time of writing, this expected connection is too small to have a significant impact on the eastern market.

The Cooper Basin in central Australia has long served the Sydney and Adelaide markets, but these reserves are largely depleted now. However, small reserve additions are continually being added around the margins of the Basin. For example, Lowry-1 (drilled by Beach) in PRl26, an exploration well located in the Southwest Patchawarra play fairway, about 4km northwest of the Middleton gas facility, targeted stratigraphically trapped liquids-rich gas. The well intersected 3.3m of net pay and was cased and suspended as a future producer, with a two-hour drill stem test conducted over the interval between 2586- 2593m. The well flowed at 9.4 million cubic feet a day on a 48/64-inch choke at 955 psig well-head pressure. About 34 barrels of condensate was recovered at a rate of about 400 bopd. The Middleton gas facility is being expanded from 25 MMscf/d to 40 MMscf/d to accommodate these successes.

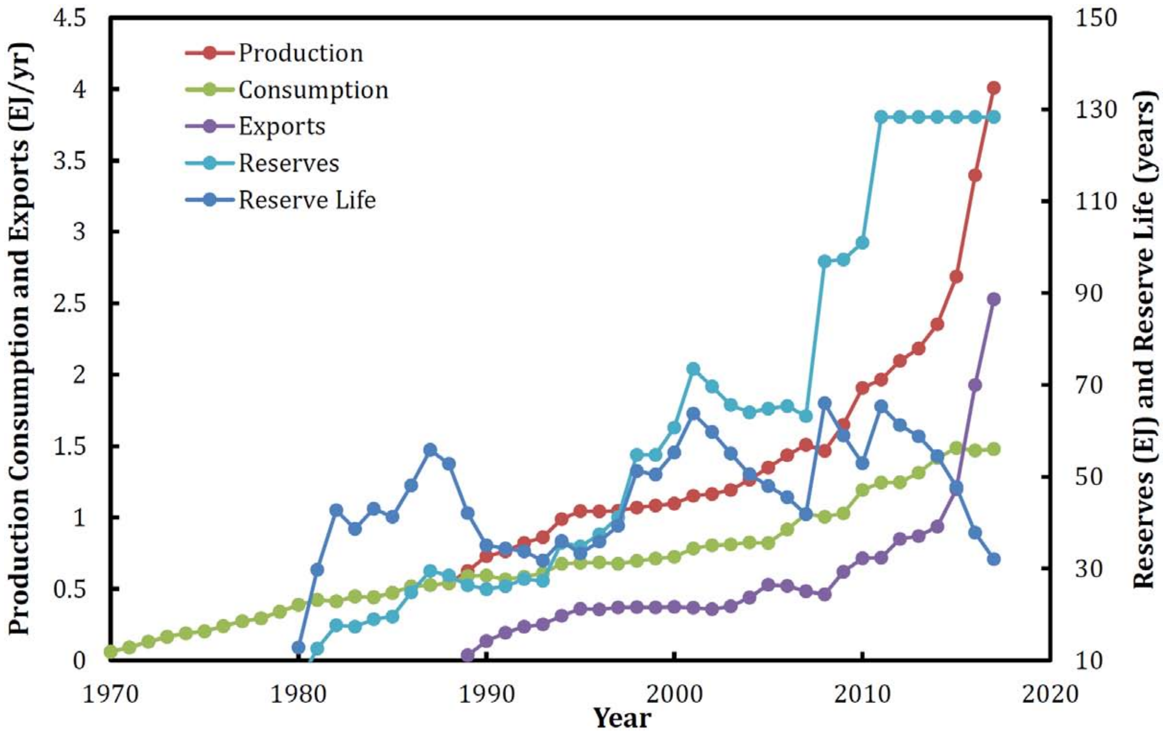

Figure 3—Historical Australian Natural Gas Production

Table 3—Current Australian Gas Domestic Demand and Forecast, by Region.

	(PJ)	(PJ)	(PJ)	growth 2014-2015 to 2049-50
Eastern market	1052	2459	2703	2.7
Western market	1729	3408	3735	2.2
Northern market	328	881	960	3.1
Total	**3109**	**6748**	**7398**	**2.5**

East Coast LNG project overview

In the Surat and Bowen basins in Queensland on the east coast of Australia there are large reserves of coal, containing large quantities of adsorbed methane. Australia began exporting gas produced from these coal seams, as liquefied natural gas (LNG), to Asian markets in January 2015. This represented the first time that coal seam gas (CSG) or (CBM) had been developed with the express purpose of liquefied export. The volumes of CSG being converted to LNG are rising rapidly reaching 1,405 BCF in 2017 [1] and are expected to surpass 1800 BCF in 2020. This gas is converted to LNG in three processing plants located on Curtis Island, just offshore from Gladstone. The first of these plants, operated by QGC (now a unit of Shell), commenced operation in December 2014. The plant operated by Santos (GLNG) commenced operations in October 2015 and the plant operated by APLNG, commenced operations in January 2016. Each operator has two trains, making a total of six trains capable of producing a total of 25.3 Mtpa.

The Surat Basin primarily hosts Jurassic age coals, while the Bowen Basin hosts Permian coals (see Figure 4). The coals are extensive and ubiquitous throughout the basins but the developments target the sweet spots where CSG production can be optimized and maximized.

Table 4 shows the principal field names that have been developed in each basin. Table 5 shows the CSG reserves of the principal operators, including Arrow Energy. While Arrow does not operate an LNG plant, its considerable CSG reserves feed gas to the current plants, as well as to the eastern domestic market. In December 2017 Arrow Energy and Shell agreed on one of the largest gas supply deals on Australia's east coast, to bring to market a large proportion of Arrow's CSG reserves. The deal between Arrow and Shell is spaced over 27-years and will commercialise a large proportion of Arrow's gas reserves in the Surat Basin, which are approximately 9.5 trillion cubic feet or around 9,500 PJ. Arrow is owned equally by PetroChina and Shell. This contract will commence with the expansion of Arrow's Tipton CSG field, near Dalby. The current Queensland total gas supply is about 1,450 PJ/yr (4,000 TJ/d), of which Queensland residential and industrial demand is approximately 178 PJ/yr. The rest of the production goes south to markets in NSW or the LNG export market. First gas production under this new contract is expected by 2020, and, under the terms of the contract, will bring an additional 240 PJ/yr or (655 TJ/d) of gas into the Queensland domestic and export markets.

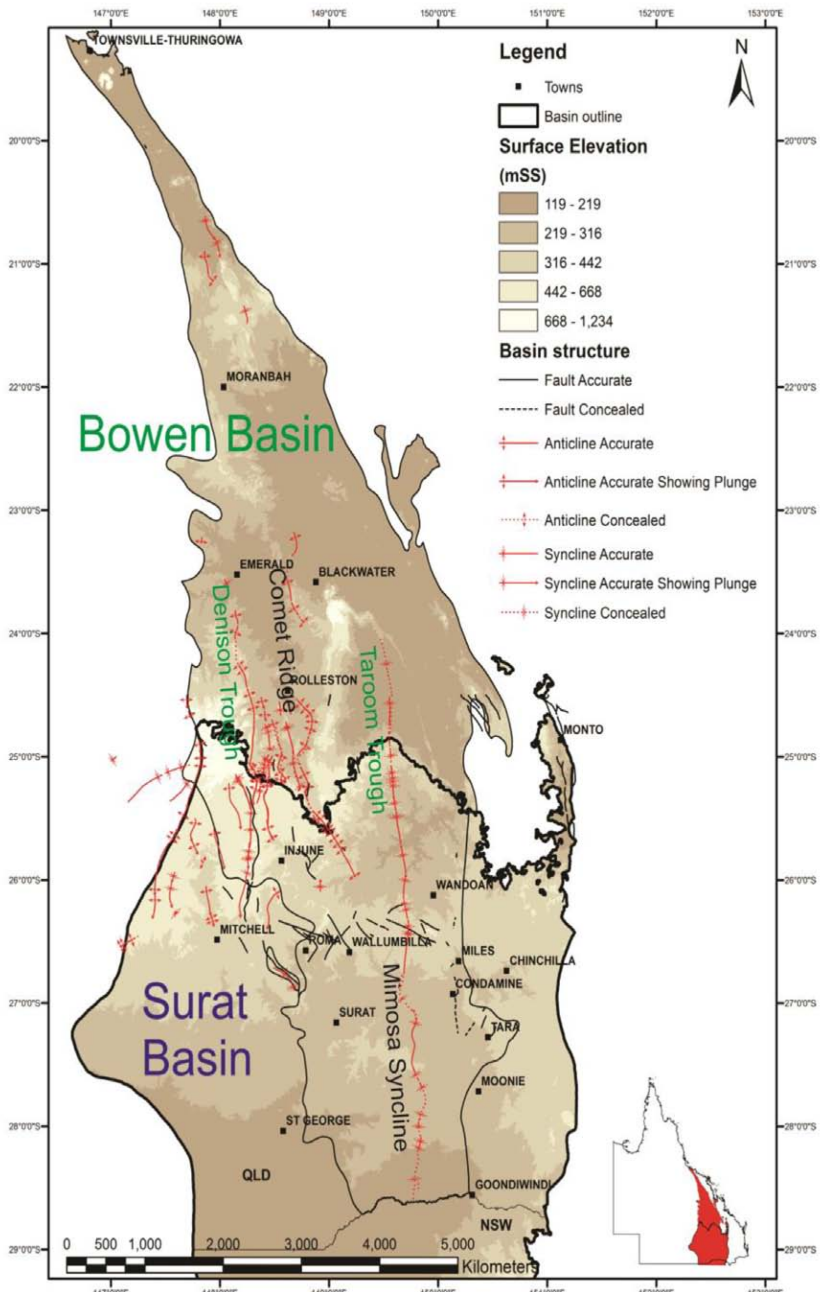

Figure 4—Surat and Bowen Basins in Queensland [2]

Table 4—Queensland's CSG Fields

Field	Basin	Formation	Field	Basin	Formation
Arcadia	Bowen	Bandana	Hopelands	Surat	Walloons
Blackwater	Bowen	Baralaba	Ironbark	Surat	Walloons
Carborough	Bowen	Baralaba	Isabella	Surat	Walloons
Dawson River	Bowen	Baralaba	Jammat	Surat	Walloons
Durham Ranch	Bowen	Bandana	Janus	Surat	Walloons
Fairview	Bowen	Bandana	Jen	Surat	Walloons
Harcourt	Bowen	Baralaba	John	Surat	Walloons
Lilyvale	Bowen	Baralaba	Jordan	Surat	Walloons
Membrance	Bowen	Bandana	Kainama	Surat	Walloons
Meridian	Bowen	Baralaba	Kainama North	Surat	Walloons
Moranbah	Bowen	Baralaba	Kate	Surat	Walloons
Moura	Bowen	Baralaba	Kedron	Surat	Walloons
Mungi	Bowen	Baralaba	Kenya	Surat	Walloons
Nipan	Bowen	Baralaba	Kenya East	Surat	Walloons
Peat	Bowen	Baralaba	Kogan	Surat	Walloons
Scotia	Bowen	Baralaba	Lauren	Surat	Walloons
Spring Gully	Bowen	Bandana	Lawton	Surat	Walloons
Springwater	Bowen	Bandana	Long Swamp	Surat	Walloons
Timmy	Bowen	Baralaba	Maisey	Surat	Walloons
Vermont	Bowen	Baralaba	Marcus	Surat	Walloons
Alex	Surat	Walloons	Margaret	Surat	Walloons
Argyle	Surat	Walloons	Matilda	Surat	Walloons
Barney	Surat	Walloons	Meenawarra	Surat	Walloons
Barney	Surat	Walloons	Michelle	Surat	Walloons
Bellevue	Surat	Walloons	Milmerran	Surat	Walloons
Berwyndale	Surat	Walloons	Mimas	Surat	Walloons
Berwyndale South	Surat	Walloons	Orana	Surat	Walloons
Bowenville	Surat	Walloons	Orana North	Surat	Walloons
Broadwater	Surat	Walloons	Pandora	Surat	Walloons
Burunga Lane	Surat	Walloons	Paradise Downs	Surat	Walloons
Cameron	Surat	Walloons	Peebs	Surat	Walloons
Carla	Surat	Walloons	Pegasus	Surat	Walloons
Castledean	Surat	Walloons	Phoebe	Surat	Walloons
Celeste	Surat	Walloons	Pinelands	Surat	Walloons
Clunie	Surat	Walloons	Plainview	Surat	Walloons
Codie	Surat	Walloons	Poppy	Surat	Walloons
Combabula	Surat	Walloons	Portsmouth	Surat	Walloons
Condabri	Surat	Walloons	Punchbowl	Surat	Walloons
Cougals	Surat	Walloons	Ramyard	Surat	Walloons
Daandine	Surat	Walloons	Reedy Creek	Surat	Walloons
Dalby South	Surat	Walloons	Rhea	Surat	Walloons
Dalwogen	Surat	Walloons	Roma	Surat	Walloons

Field	Basin	Formation	Field	Basin	Formation
David	Surat	Walloons	Rubyjo	Surat	Walloons
Dione	Surat	Walloons	Sean	Surat	Walloons
Don Juan	Surat	Walloons	Stratheden	Surat	Walloons
Dundee	Surat	Walloons	Talinga	Surat	Walloons
Glendower	Surat	Walloons	Tethys	Surat	Walloons
Glenora	Surat	Walloons	Tipton	Surat	Walloons
Glibert Gully	Surat	Walloons	Titan	Surat	Walloons
Harry	Surat	Walloons	Wollobee	Surat	Walloons

Table 5—Reserves aligned to the four projects (GLNG, QCLNG, APLNG and Arrow Energy) as at 30 June 2015 [2]

Project	2P Reserves (PJ)
1. GLNG (Santos operator)	5376
2. QCLNG (QGC operator)	10326
3. APLNG	13053
4. Arrow Energy	9494

Commercial CSG production began in the Bowen Basin in 1997 and in the Surat Basin in 2004 (see Figure 5). As of 2018, 98% of the natural gas being produced in Queensland is coal seam gas. 80% of the gas being produced in Queensland is being exported as LNG. The CSG production and LNG export is expected to reach its peak and plateau in 2020.

Coal seam gas requires the coals to be dewatered before the gas can be desorbed from the coal. This water is treated in reverse osmosis plants to remove any salt and is then used for irrigation or watering stock. Underschultz, Vink [3] have reviewed the water production from coal seam gas in Queensland and concluded that the water production is expected to peak at about 70-80 GL/y, which is only 25% of the original forecasts from independent authorities and 70% of estimates forecast by industry (see Figure 8). Figure 6 shows that the produced volumes of water from CSG wells is closely related to the number of wells put into production. Figure 7 shows the historical and projected future water production from CSG wells. This contrasts with what was projected to be produced from CSG wells when the developments were first proposed, as shown in Figure 8. This is discussed by Towler, Firouzi [2] and Underschultz, Vink [3].

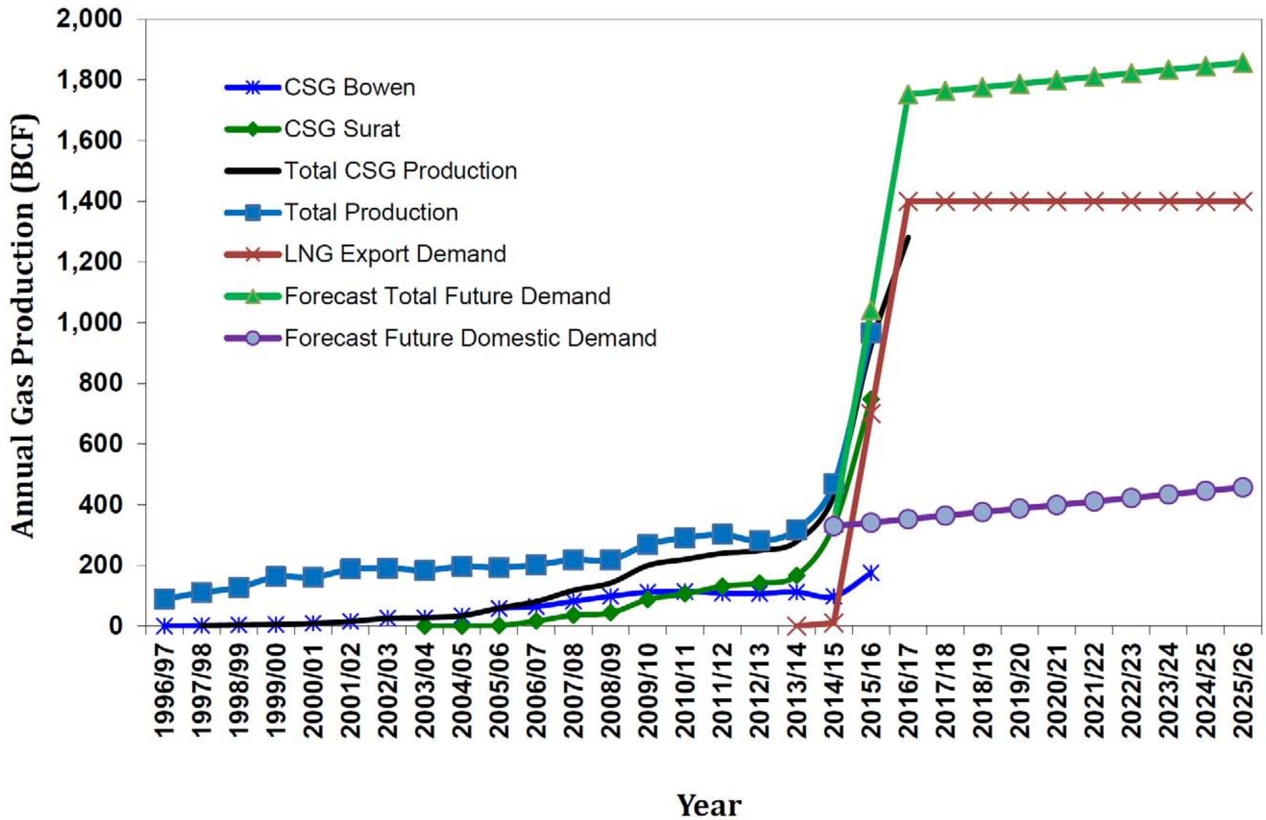

Figure 5—Historical Gas Production in Queensland

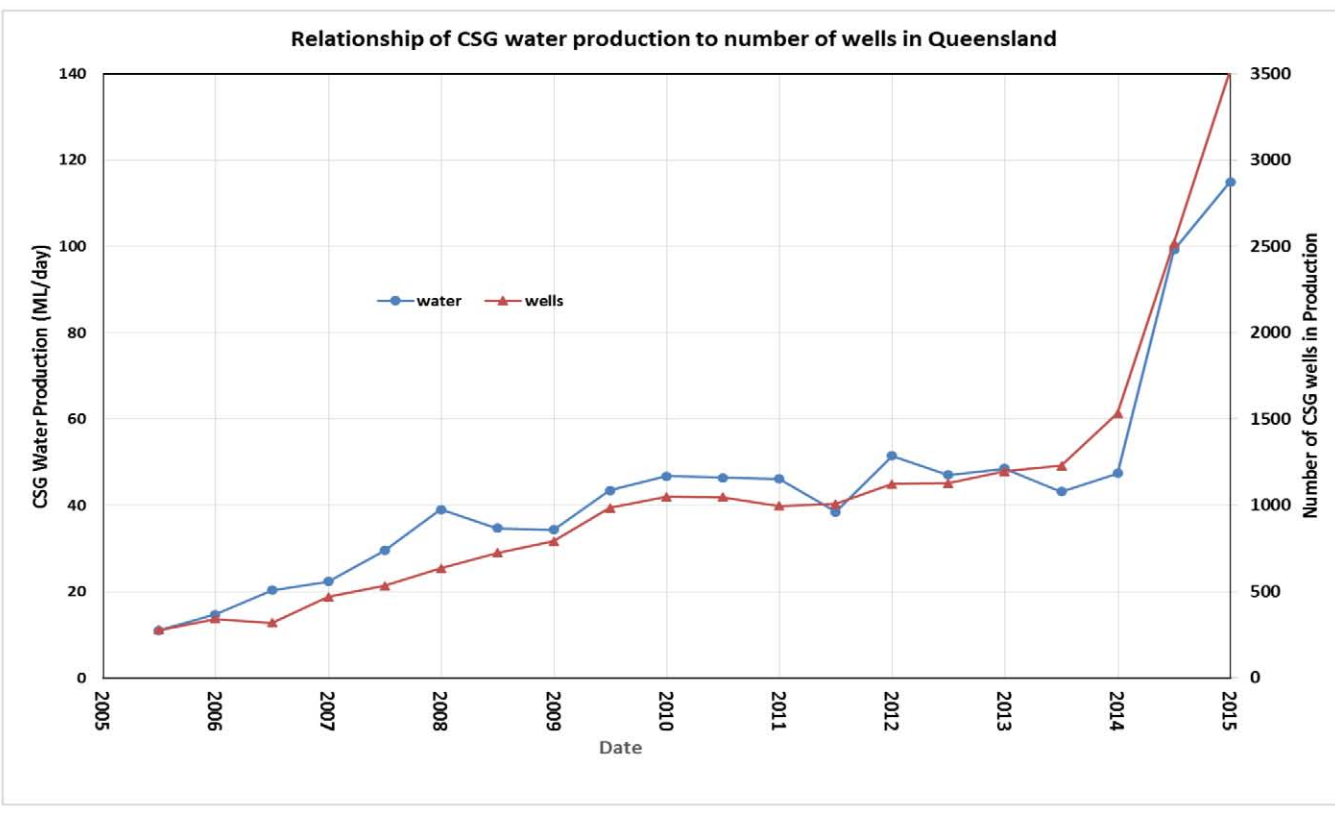

Figure 6—Relationship of CSG water Production to Number of CSG Wells in Queensland

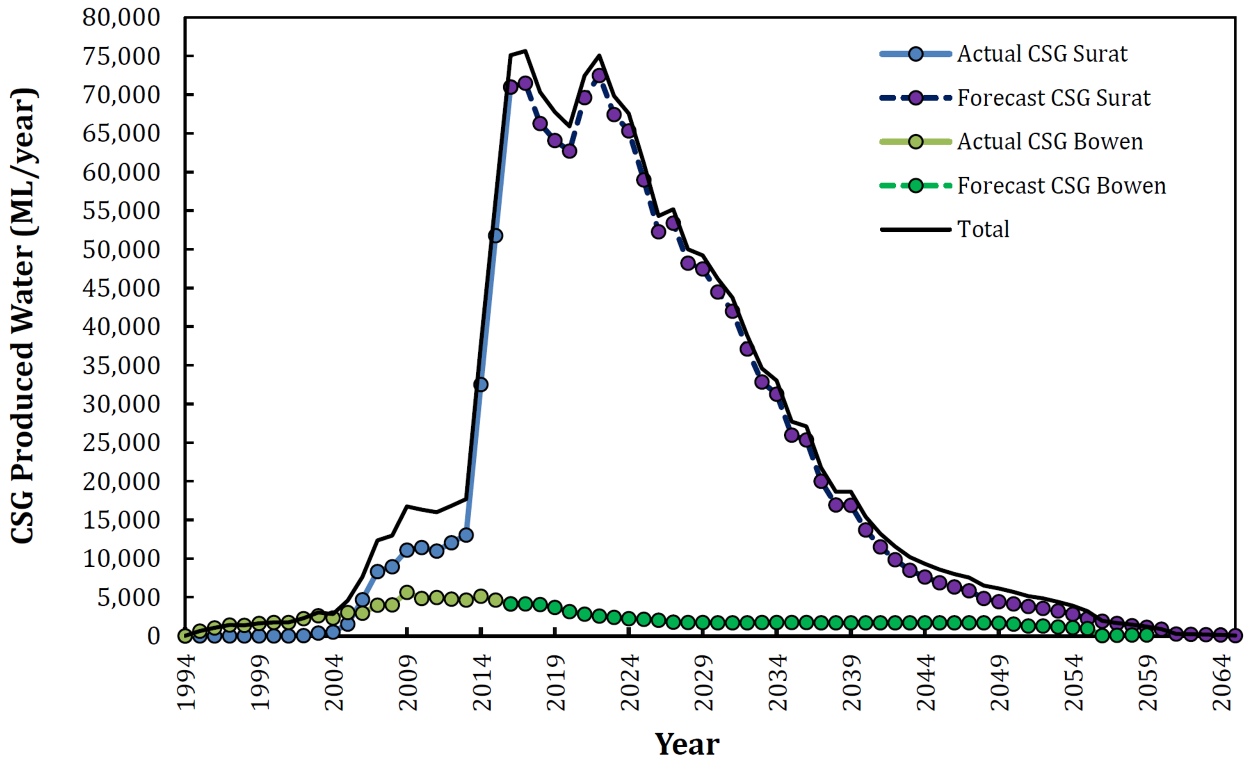

Figure 7—Historical and Future Water Production Forecast from CSG Wells. Modified after [4]

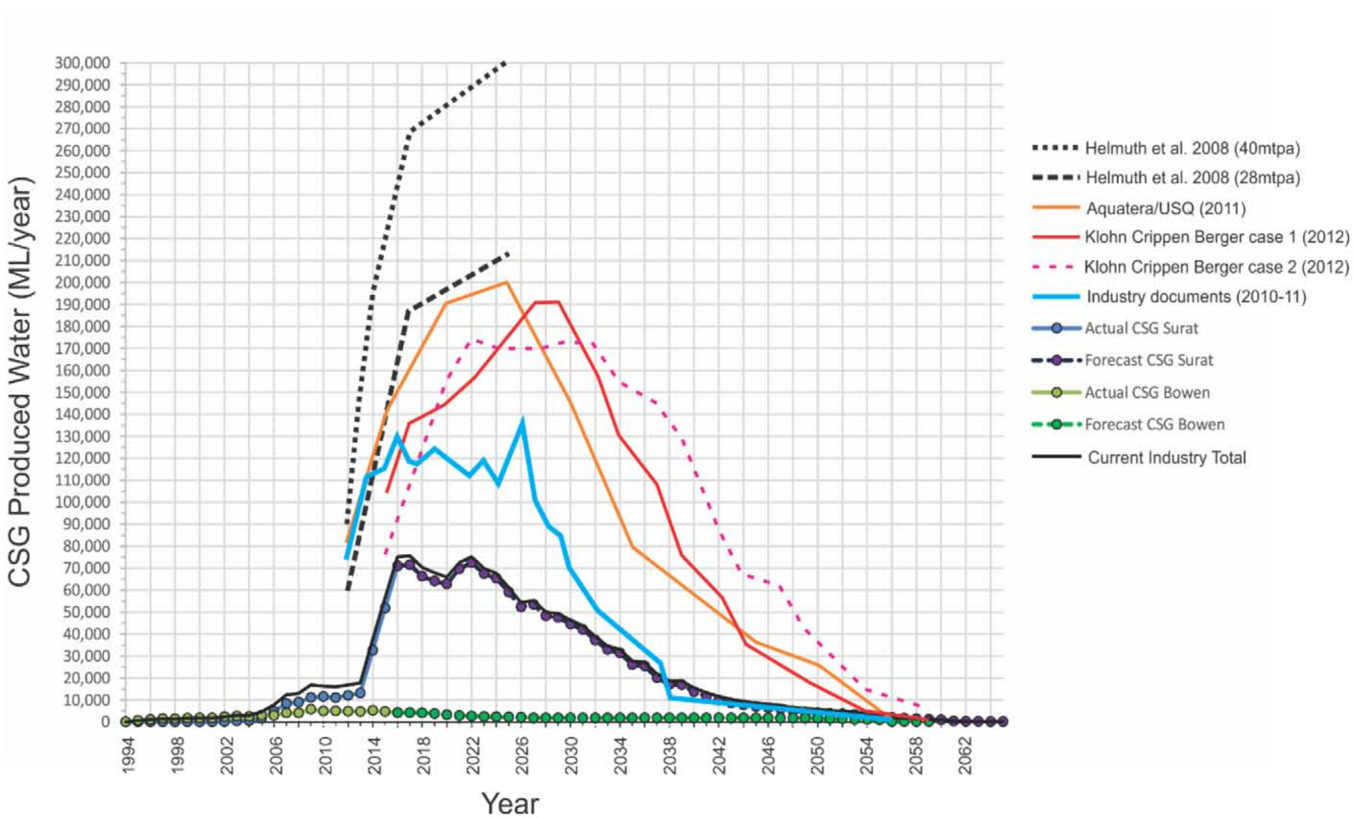

Figure 8—Survey of CSG Water Production Forecasts Prior to Development [3]

There are considerable technical challenges associated with the CSG production in Surat and Bowen basins. Some of these include:

- Predicting geological heterogeneity
- Relative permeability characteristics of coal cleats
- Fines production from the inter-burden
- Reservoir stimulation to improve productivity
- Time dependent or stress dependent permeability
- Slugging and optimisation of production well operations
- Well decommissioning
- Fugitive methane
- Attic gas
- Associated water management
- Salt and brine disposal
- Cumulative impacts and great artesian basin water level management
- Co-existence and social licence to operate

The unintended consequences

The start of three CSG to LNG projects, each with two LNG trains, was an intense period of construction and drilling from the first final investment decision (FID) in October 2012, until the last LNG train startup in October 2016. The total investment to 2017 in CSG and LNG development is approx. $70 billion [5].

Table 6—CSG to LNG Project key events: Source: company public announcements

Project (Operator)	Key Event	Date
QCLNG (Shell)	Final Investment Decision	October 2012
	Train #1 startup	December 2014
	Train #2 startup	July 2015
GLNG (Santos)	Final Investment Decision	January 2011
	Train #1 startup	October 2015
	Train #2 startup	June 2016
APLNG (Origin Energy/ConocoPhillips)	Final Investment Decision	July 2011
	Train #1 startup	January 2016
	Train #2 startup	October 2016

Not only was there intense drilling activity during the startup phase peaking at over 350 wells per quarter, but drilling continues at 136 wells in the January to March 2018 quarter, in support of the high volumes of gas required for the LNG and domestic markets (see Figure 9).

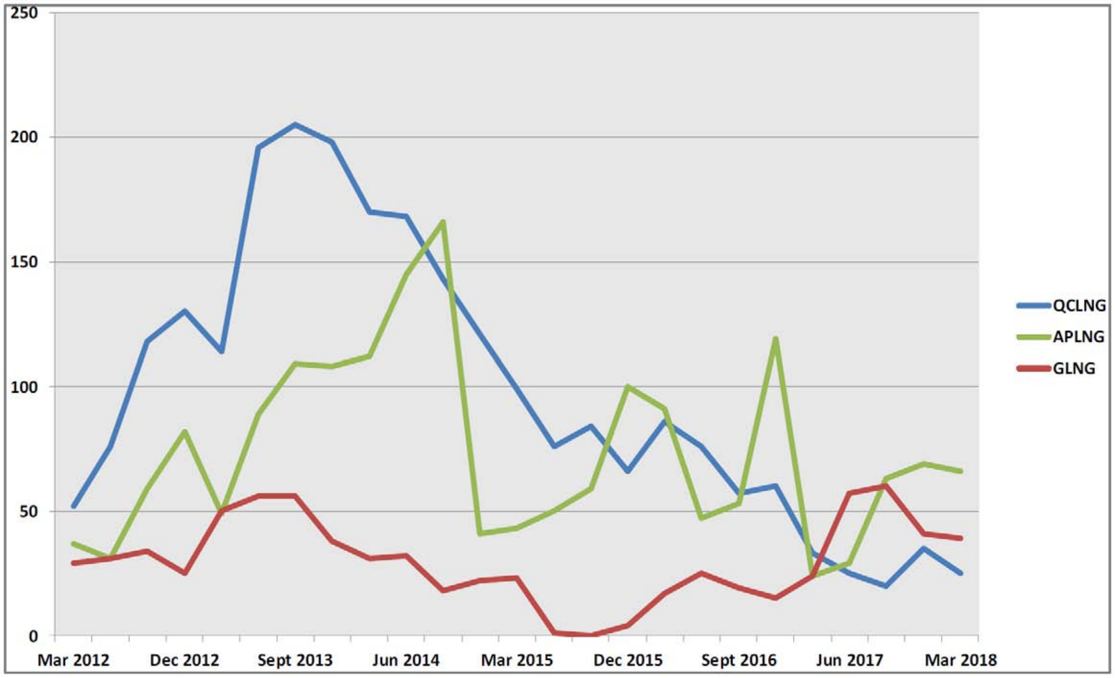

Figure 9—CSG development wells drilled, by operator [6]

The local communities in the Surat Basin had experience of the gas industry which goes back to as early as 1900, with large volume gas production piped to Brisbane commencing in March 1969. None of this activity was of the scale of the CSG development. In 2018, 2,188 landholders have over 5,107 agreements [7] with gas operators for access to their properties. This is the most intense drilling and well activity ever seen in Australia. Not only did this impact local towns and communities, but also agricultural activity. The Surat Basin supports a wide variety of agricultural operations ranging from open grazing land, to intense cotton and multiple cropping activities. The latter can often involve large capital investment to laser level land and construct dams for irrigation, as well as the associated agricultural equipment.

Most comparable onshore gas fields in places, such as North America, do have similar or even higher well densities and activities. The difference in Queensland is that the drilling was for a world first CSG to LNG projects, with hard start dates and high volume requirements to meet firm contracts, whereas in North America, the deep integrated markets (e.g. at Henry Hub) mean gas can be more readily commercialized in smaller tranches or adapted to local constraints.

Not only was there a lack of experience by landholders and local communities with the high activity, and dealing with gas companies on tight schedules, but the gas companies themselves had little experience in dealing with intensive agriculture operations. The result was a build-up of angst, mistrust and poor communication between stakeholders. Activist groups such as Lock the Gate and the Basin Sustainability Alliance sprung up to address landholder concerns. Not all activism was focused on landholder rights. There were also overlaps with anti-fossil fuel movements [8, 9] and concerns about the impact on the greenhouse gas emissions.

This also engaged the State and Federal Governments who responded with new regulations and legislation. The Federal Government passed legislation [10] in 2013 to amend the Environmental Protection and Biodiversity Conservation Act 1999 (EPBC Act) to include consideration of the potential impact on water resources by CSG development and large coal mining activities.

The Queensland Government adapted regulations, and passed legislation including the Strategic Cropping Land Act 2011 [11] to protect cropping land, and to manage the impacts of development and preserve the productive capacity of that land for future generations. It also passed the Gasfields Commission

Act 2013 [12], which established an independent commission as a statutory body to manage and improve the sustainable coexistence of landholders, regional communities and the onshore gas industry in Queensland.

These actions addressed many of the concerns of the impacted areas, and with the increased experience of the gas companies and landholders, the CSG activity is becoming more of a part of the regional economies.

Regulation and the consumer need's for reliable, affordable and clean energy

Curtis Island is the site of large world scale LNG facilities. Only Qatar, Malaysia and Western Australia produce more LNG. With the startup of the Curtis Island LNG projects, gas demand on the east coast of Australia went from 712 PJ in 2014 to 1,832 PJ (of which 709 PJ was domestic) in 2017 - an increase of 257% in three years.

There are few examples in the world where a large scale LNG operation has commenced in a mature domestic gas market. Most LNG projects at the time of the project FID's were based on otherwise stranded gas reserves, with no connection to material domestic markets. Since that time, North America has become a more active LNG exporter, but this is small relative to its domestic gas market.

The connection of the LNG plants to a domestic market mean that the project operators may buy gas from the domestic market when:

- the net back price gives a positive margin;
- capital is constrained. With capital investment of around $70 billion, the LNG project owners could be expected to be tightly managing capital. Deferring capital investment for drilling gas wells by buying gas from the domestic market would be a real option in that financial situation;
- there is a reserves shortfall. If reserves were below the requirement to meet LNG contracts, then buying gas to meet firm contracts could be justified.

For context, in 2017, 40 PJ of gas flowed into Queensland, which was 2% of the total east coast gas production. For the first half of 2018, Queensland exported 4.9 PJ to southern states i.e. Queensland is now self-sufficient in gas to meet its domestic and LNG demand.

The Australian Competition & Consumer Commission (ACCC) noted in its April 2016 report [13] that "the changes brought increased uncertainty and complexity to the market, particularly for commercial and industrial users. These users were now required to adapt to a situation where they find it difficult to get multiple offers for supply, prices were significantly higher and more volatile, and non-price terms were less flexible than in the past".

Faced with this evidence, the Federal Government used its custom powers [14] as amended by the Customs (Prohibited Exports) Amendment (Liquefied Natural Gas) Regulations 2017 [15], to potentially limit exports of LNG under the Australian Domestic Gas Security Mechanism (ADGSM) [16]. Restrictions only apply if the Minister determines that there is a gas shortfall year. One such review has been held in 2017 when the Minister gave notice of his intent to consider whether to determine 2018 as a domestic shortfall year. The Australian Energy Market Operator (AEMO) forecast a shortfall [17] and the industry stakeholders and LNG exporters were consulted. The result was a Heads of Agreement [18] signed by the Prime Minister and the LNG exporters to maintain a secure and affordable domestic gas supply for 2018 and 2019.

The ADGSM is designed to ensure there is a sufficient, reliable supply of natural gas to meet the forecast needs of gas users within Australia. However, it does not address the broader energy (gas and electricity) ‘trilemma’ of optimising energy affordability, reliability and emissions.

The National Energy Guarantee (NEG) is proposed by the Federal Government with two parts to the guarantee:

1. A reliability guarantee to deliver the right level of dispatchable energy

2. An emissions guarantee to address greenhouse abatement commitments

The approach is technology neutral in that it does not determine which technology is to be used to meet the Guarantees. There is no guarantee on affordability or cost, but it is a policy designed to give certainty for future investment, with the idea that more investment will increase competition and put downward pressure on prices.

Northern Territory

Historically the gas supply in the Northern Territory has come from the offshore Bonaparte Basin and the onshore Amadeus Basin. Though these basins are not completely depleted, they have passed their peak and are now on decline. The primary offshore gas fields in the Bonaparte Basin are the Bayu and Undan fields that are processed and converted to LNG by a consortium led by ConocoPhillips. This plant is at Wickham Point, near Darwin. ConocoPhillips is now considering the development of other fields in the basin, particularly Barossa and Caldita and the Greater Poseidon group of fields (Pharos, Boreas, Kronos, Zephros and Poseidon). The plan is to send the gas from these fields through the same pipeline and process the gas at the same plant at Wickham Point, which is a few kilometres south of the city of Darwin.

Another potential source of gas supply from the onshore region of the Northern Territory is the Beetaloo sub-basin (from within the Georgina Basin). A new 12 inch pipeline to connect the Northern pipeline grid to the east coast market was completed in July 2018. This line originates very close to the gas in the Beetalooo sub-basin. This pipeline is currently designed to carry only 90 TJ/day (33 PJ/yr) but, if and when the demand arises, it is postulated that the pipeline could be expanded to carry 700 TJ/day (255 PJ/yr). This would have a major impact on the east coast gas supply. The 12 inch pipeline could reach 160 TJ/d with midline compression, but the 700 TJ/d would need a looped or duplicated pipeline. Alternatively, there has been discussion of building a larger line from Mereenie in the Amadeus Basin to Moomba in the Cooper Basin. Moomba has a larger and more direct connection into the east coast grid, but the potential gas supply at Mereenie is smaller than the potential supply from Beetaloo.

The Beetaloo sub-basin may have the capability to produce up to 700 TJ/day, but this is not proven and it is tight shale gas, which will require hydraulic fracture stimulation to be produced at economic rates. However, now that the Northern Territory fracking ban has been lifted (April 2018), if the economics are favourable and firm contracts can be secured, the Beetaloo sub-basin might be part of the solution to the supply of gas to domestic markets on the east coast. However, the domestic demand for this gas will also have to compete with potential LNG export markets.

The majority of the Beetaloo sub-basin is leased to a joint venture of Origin Energy (70%) and Falcon Oil and Gas (30%) and shown in Figure 10. The primary target in the sub-basin is the Velkerri B shale gas pool, with a secondary target in the Kyalla formation. Origin has submitted estimates of gas in place in the Velkerri shale to the Northern Territory Government, as shown in Table 7.

Table 7—Middle Velkerri B Shale Volumetric Estimates from Operator, Origin Energy

	Gross	Net Attributable
	Best Estimate	Best Estimate
Area km^2	16,145	4,751
OGIP (TCF)	496	146
Combined Recovery Factor	16%	16%
Technically Recoverable (TCF)	85	25
OGIP/unit area (BCF/km^2)	31	31

In addition, Origin has published a contingent gas resource estimate using probabilistic methods and reservoir evaluation data, in addition to regional seismic data and these are shown in Table 8.

Table 8—2C Contingent Gas Resource Estimates for the Middle Velkerri B Shale Pool within EP76, EP98 and EP117 from Origin Energy

Measured and Estimated Parameters	Units	Best Estimate
Area	km^2	1,968
Original Gas In Place (OGIP)	TCF	61.0
Gross Contingent Resource	TCF	6.6
Net Contingent Resource	TCF	1.94

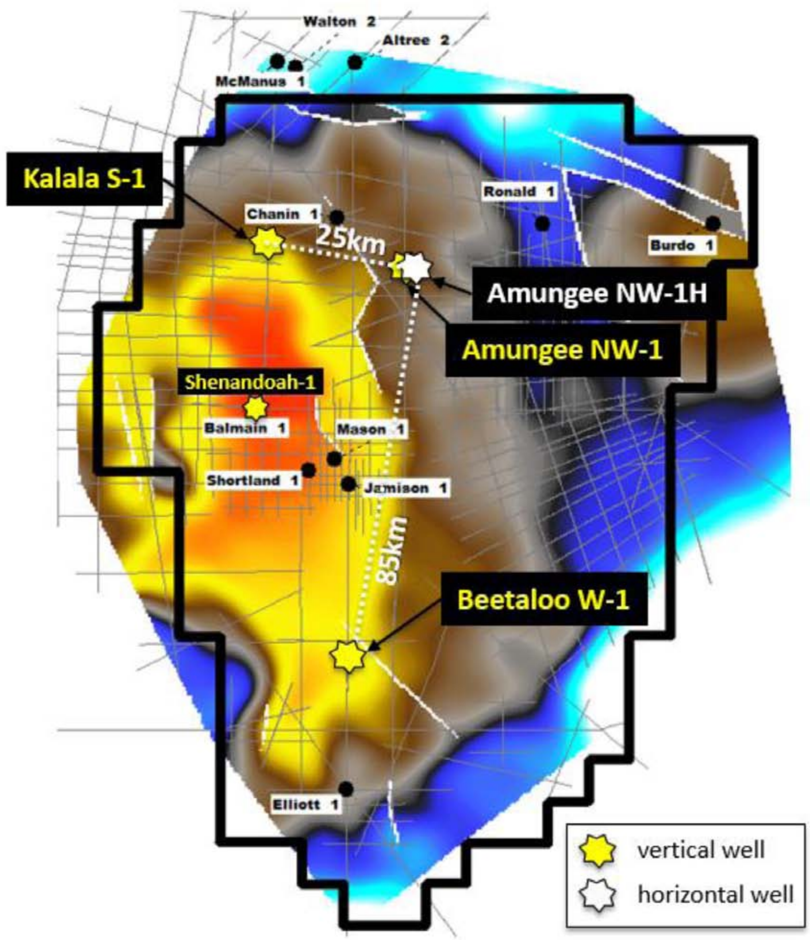

Figure 10—Wells in Northern Territory's Beetaloo Sub-Basin (diagram courtesy of Falcon Oil and Gas)

The Kyalla shale resource is still being assessed, but there is also a lot of optimism about its potential. At the time of writing it is not completely clear what is the cost of developing and producing this gas, but it is quite likely that the Beetaloo sub-basin contains a lot of gas that might contribute to Australia's future natural gas supply.

Western Australia's Offshore

The great majority of Australia's historical gas production and LNG exports have come from the North West Shelf in the Carnarvon Basin, offshore from Western Australia. While some of this gas has been used domestically in Western Australia, none of it has supplied the eastern markets in any other Australian state or territory. The overwhelming majority of the gas has been exported as LNG. Even so, less than half of the Basin's gas has been produced and a significant amount of gas remains in the ground in undeveloped reservoirs. New fields have been brought into production and new facilities have been built to process this gas. Further new developments are being planned to bring several other fields to the market, particularly as LNG for export. Most of the recent developments have been stand-alone developments with new processing facilities being built at considerable cost. However, this approach is likely to be reexamined for future projects. Table 9 shows all of Australia's LNG export facilities. This table shows that Australia currently has the capacity to export 95 million tonnes per annum (Mtpa) with one more plant (the 4.9 Mtpa Pluto train 2, which will serve the Pluto, Xena and Scarborough fields) to be constructed and beginning processing in 2025. In order to keep costs low, additional field development, such as the undeveloped Carnarvon Basin, Bonaparte Basin and Browse Basin fields, are likely to be processed through existing facilities. Smaller remote fields may also be developed with floating LNG facilities, such as what has happened at Prelude, to be discussed later. These new approaches to development are likely to be the future of offshore gas field development, particularly in Western Australia and Northern Territory.

Table 9—Australia's LNG Export Facilities and Potential Future Developments.

Principal Fields	Basin	Location of Plant	Plant Capacity Mtpa	Output in 2017 million tonnes	Output in 1st Qtr 2018 million tonnes	Operator	First Gas
North Rankin, Goodwyn	Carnarvon	Burrup Park	24	12	3.5	Woodside	Jan-1989
Bayu, Undan	Bonaparte	Wickham Point	3.7	3.6	0.9	Conoco	Jan-2006
Pluto, Xena	Carnarvon	Burrup Park	4.9	4.8	1.2	Woodside	Apr-2012
Coal seam gas	Surat and Bowen	Curtis Island	9	8	2	QCLNG	Jan-2015
Coal seam gas	Surat and Bowen	Curtis Island	8	7	2	GLNG	Sep-2015
Coal seam gas	Surat and Bowen	Curtis Island	9	7	2	APLNG	Dec-2015
Gorgon, Io, Jansz	Carnarvon	Barrow Island	15.6	15	3.5	Chevron	Mar-2016
Wheatstone, Iago	Carnarvon	Ashburton	8.9	2	2	Chevron	Oct-2017
Ichthys	Browse	Bladin Point	8.9	NA	NA	Inpex	Jul-2018
Prelude, Concerto	Browse	FLNG	3.6	0.9	0.9	Shell	Sep-2018
Pluto, Scarborough	Carnarvon	Burrup Park	4.9	NA	NA	Woodside	Jan-2023
Awaiting development		Potential LNG plant					
Torosa, Brecknock	Browse	Burrup Park	NA	NA	NA	Woodside	NA
Sunrise, Sunset	Bonaparte	Wickham Point	NA	NA	NA	Woodside	NA
Cash, Maple	Bonaparte	FLNG	NA	NA	NA	PTTEP	NA
Barossa, Caldita	Bonaparte	Wickham Point	NA	NA	NA	Conoco	NA
Petrel, Tern, Frigate	Bonaparte	FLNG	NA	NA	NA	Engie	NA
Poseidon, Pharos, Boreas	Bonaparte	FLNG	NA	NA	NA	Conoco	NA
Totals			**100.5**	**60.3**	**18**		

Inpex is leading the development of the Ichthys field in the Browse Basin, offshore from the northern part of the Western Australia (see Figure 12). Because it is closer to Darwin, the LNG plant has been located at Bladin Point, which is quite near Conoco's LNG plant at Wickham Point near the city of Darwin in the Northern Territory. The Bladin Point plant is connected via pipeline from the Ichthys field. Inpex has announced that Ichthys contains reserves of 12.8 TCF (3.7×10^{11} m^3) of gas and 500 MM-barrels of condensate. The pipeline has been built to the processing facilities at Bladin Point is 890 km long.

Inpex announced in June 2018 that they had commissioned the project's central processing facility, to be known as the Ichthys Explorer (see Figure 11. Ichthys Explorer LNG facilities at Bladin Point, near Darwin. (Photo courtesy of Inpex) This was the last remaining piece of onshore or offshore infrastructure to be completed on the US$40 billion project, which has faced multiple cost overruns and delays from its original 2016 planned commencement date. At the time of writing (July 2018), all that remained before gas flowed from the wellhead were final safety inspections. Inpex indicated that the project would proceed with the shipment of cargoes, giving an expected start-up date of August-September 2018. Start-up was confirmed on July 30th, 2018. The export schedule was expected to start with condensate followed by LNG and LPG. Inpex is 62.245% owner of the project, with France's Total holding 30% and the other partners comprising CPC Corporation, Tokyo Gas, Osaka Gas, Kansai Electric Power, JERA and Toho Gas. It was also reported that the utility partners in the project were seeking five LNG cargoes for delivery into Japan and Taiwan over the July to September 2018 period to make up for those they were unable to source as a result of delays. The project has the capacity to produce and export approximately 8.9 million tonnes of LNG and 1.65 million tonnes of LPG per year, along with 100,000 barrels of condensate per day, at its peak. Inpex also recently acquired a further large exploration block (WA-532) just south of Ichthys field that they hope will yield further large finds of gas that will eventually feed into the same processing facilities.

Figure 11—Ichthys Explorer LNG facilities at Bladin Point, near Darwin. (Photo courtesy of Inpex)

Shell has recently developed the Prelude field in the Browse basin (see Figure 12), which is the first floating liquefied natural gas (FLNG) facility in Australia and the first installed by Shell. First gas is expected in September 2018. The FLNG development means that Shell will not have to pipe gas onshore for processing. All production processing and loading of the LNG will be conducted on the FLNG vessel, which is moored in the Browse Basin, about 250 kilometres from the West Australian coast and 475 kilometres from Broome, in water that is 250 metres deep. The facility will produce and process gas from the Prelude and Concerto fields, which are located just north-east of the Ichthys field. The FLNG has a capacity of 3.6 million tonnes per year (Mtpa) of LNG plus 1.3 Mtpa of condensate and 0.4 Mtpa of LPG, which makes it similar in size to Conoco's onshore LNG facility at Wickham Point that serves the Bonaparte basin fields. Shell opted for a floating facility because it was cheaper and more flexible. It can be moved from one gas field to another, enabling them to economically access fields that would otherwise be too difficult and too costly to develop. The facility is operated by Shell (67.5%) with joint venture partners Inpex (17.5 per cent), Kogas (10 per cent) and OPIC (5 per cent). This FLNG trend could become the norm for small remote offshore fields and is being considered by Engie for the Frigate-Petrel-Tern group of fields and by PTTEP for the Cash-Maple field, all in the Bonaparte basin.

The Browse Basin is also estimated to contain additional contingent volumes of 15.9 trillion cubic feet of dry gas and 436 million barrels of condensate in three other fields, the Torosa (discovered and first drilled in 1971), Brecknock (discovered and first drilled in 1979), and Calliance (discovered and first drilled in 2000) fields, owned by a joint venture led by Woodside (see Figure 12). Woodside has favoured a development plan that would send this gas south via pipeline, to be processed in the North West Shelf facilities at Burrup Park, near Karratha. With the decline in production from the North Rankin-Goodwyn group of fields, there will be spare capacity in the facilities at Burrup Park. The first field in the Browse basin (Torosa) was discovered in 1971. Since 2005, Woodside has undertaken studies, preliminary engineering and front end engineering design (FEED) on a range of options. The solutions have included fixed and floating options. There was a plan to develop a processing facility at James Price Point, north of Broome. That proposal included an extensive aid package to traditional landowners, and a mandate for local employment, and the use of local businesses. But the JPP proposal was dropped in favour of Floating LNG. An FLNG unit, similar to Shell's Prelude facility, would only be sufficient for one of the reservoirs. So three FLNGs would have been needed. Woodside found they could not make FLNG commercial for the Browse reservoirs. So processing the gas at Burrup Point near Karratha is currently being investigated. Four of the six North West Shelf partners, (Woodside, Shell, BP and MIMI), are part of the Browse joint venture as well. So it is likely that processing the gas at Burrup Point makes the most economic sense. If this option goes ahead, FEED contracts are expected to begin in 2019.

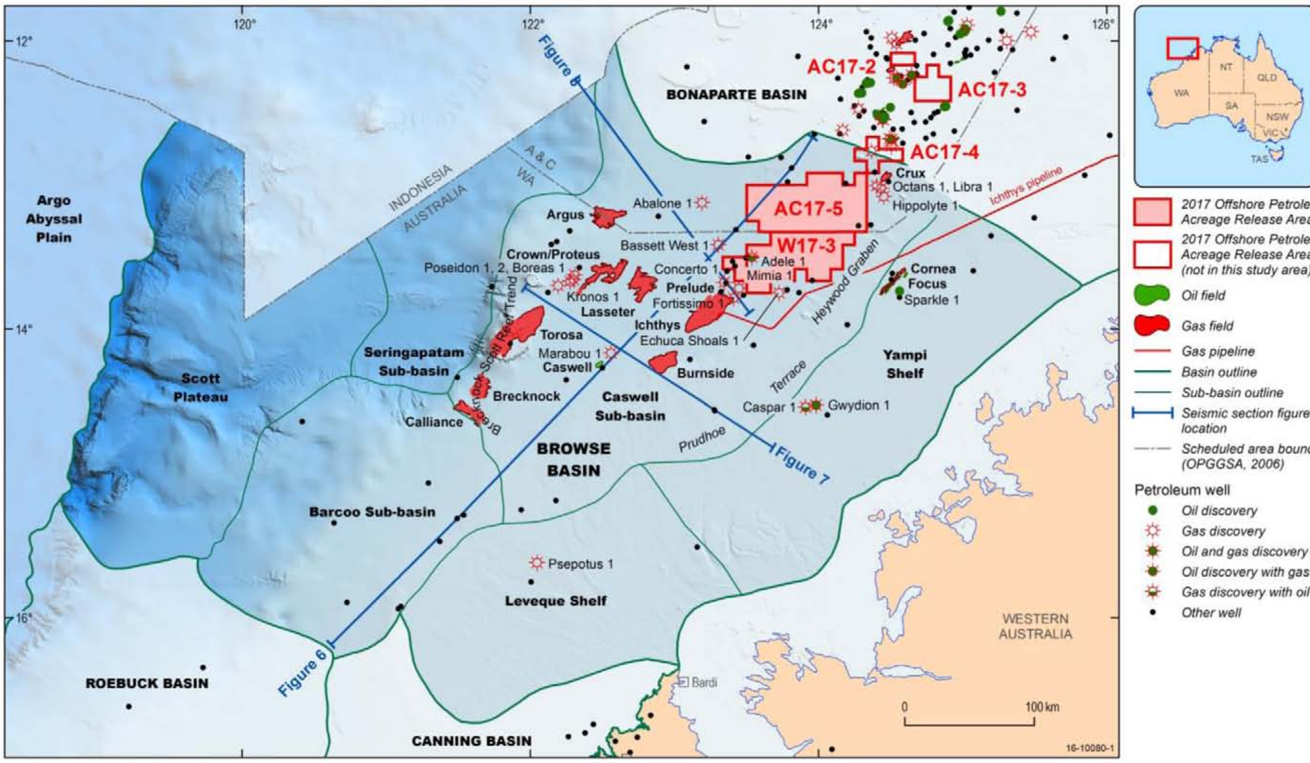

Figure 12—Gas fields in the Browse Basin, Offshore from Western Australia (figure courtesy of Geoscience Australia).

Woodside Petroleum also operates the Pluto and Xena gas fields, located about 190 kilometres offshore from Karratha, in Western Australia. The two gas fields contain approximately 5 Tcf of dry gas. The Pluto LNG facility was built adjacent to Woodside's North West Shelf LNG plant at Burrup Park. Start-up was in April 2012. The total area of the Pluto onshore facility is about 200 hectares, of which the plant and associated infrastructure cover about 80 hectares. The onshore infrastructure comprises a single LNG processing train with annualised loaded LNG production rate equivalent of 4.9 million tonne per annum (Mtpa) (100% project). Woodside notes that this is 14% higher than the 4.3 Mtpa average expected annual production capacity at the time of the final investment decision (FID) in 2007. A second Pluto train was previously planned for 3.3 million tonnes per annum, with a start-up in 2024. But currently Woodside plans to speed up plans for the Scarborough field development by expanding the Pluto Train 2 to 4.9 million tonnes per annum capacity, with start-up planned for 2025. The cost of the Scarborough development has been estimated to be A$14.57 billion, with first gas planned for 2023. A final investment decision for this has not been made yet, but is expected in 2020. Woodside is the field operator, and owns 75% of the project, after buying out ExxonMobil's 50% share in 2018. BHP holds the other 25%. First gas from Scarborough would initially go via Pluto to the nearby North West Shelf plant, and in 2024 to Pluto Train 2, whose expanded capacity could have implications for other stranded and undeveloped gas fields across the Carnarvon Basin. To facilitate the early development of fields like Scarborough, Woodside is actively investigating the installation of aninter-connect between the Pluto trains and the North West Shelf trains. This would give them greater flexibility in the event of shutdowns or early development of nearby fields.

The Gorgon Project is a joint venture between Chevron (47.3 percent), ExxonMobil (25 percent), Shell (25 percent), Osaka Gas (1.25 percent), Tokyo Gas (1 percent) and JERA (0.417 percent). It started first production on 9 March, 2016 with first LNG cargo sailing on 21 March, 2016. The third train commenced operations on 28 March, 2017. The three trains at Gorgon produce a total of 15.6 million tonnes per annum (Mtpa), with the plant located on Barrow Island. There is also a domestic gas plant attached, with the capacity to supply 300 TJ/day to the domestic market of Western Australia. The Gorgon Project also incorporates one of the world's largest carbon dioxide injection projects of 3.6 million tonne per annum (Mtpa) of CO_2.

Chevron also operate the newly commissioned Wheatstone LNG facility, which is a joint venture between Chevron (64.14 percent), Kuwait Foreign Petroleum Exploration Company (KUFPEC) (13.4 percent), Woodside Petroleum Limited (13 percent), and Kyushu Electric Power Company (1.46 percent), together with PE Wheatstone Pty Ltd, part owned by JERA (8 percent). It processes gas from the Wheatstone and Iago fields, which are located on the North Rankin-Goodwyn-Gorgon trend, southwest of Goodwyn and northeast of Gorgon. The Wheatstone plant has two LNG trains, which produce 8.9 million metric tonnes per year. The facility is located onshore at Ashburton, 12 kilometres west of Onslow. It commenced operation on 9 October, 2017 (see Figure 13).

Figure 13—The Wheatstone LNG Plant. Located at Ashburton, WA. (Picture courtesy of Chevron).

Conclusions

Australian domestic gas consumption and LNG exports have caused Australian gas production to increase rapidly in the past five years. Australia currently has the capacity to process and export 95 Mtpa of LNG, making it the world's leading exporter of LNG. When the Pluto train 2 comes online in 2025, this export capacity will increase to over 100 Mtpa. At the same time, gas reserves have not been allowed to increase because of restrictive exploration and development regulations. The high gas production is expected to level off but not decrease. Reserve life is falling rapidly, but is still within manageable limits. However, if additional reserves are not added in the near future, the reserve life will fall below 20 years by 2025. This will be a critical point for Australian gas supplies. A shortage of gas is also developing in the east coast domestic market. There are several sources of gas that can forestall this shortage, but the gas will be expensive to develop and bring to market. Unconventional and conventional reserves in Northern Territory and Western Australia need to be tied into eastern markets more strongly. However, this gas will have to compete with LNG export demands.

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